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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A RATE INCREASE.	DOCKET NO. E-01773A-04-0528
IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE.	DOCKET NO. E-04100A-04-0527 **NOTICE OF FILING REBUTTAL TESTIMONY**

In relation to the Arizona Electric Power Cooperative, Inc. ("AEPCO") rate matter, AEPCO has filed the rebuttal testimony of Messrs. Dirk Minson and Gary E. Pierson.

In relation to the Southwest Transmission Cooperative, Inc. ("SWTC") rate matter, SWTC has filed the rebuttal testimony of Messrs. Dirk Minson and Gary E. Pierson.

RESPECTFULLY SUBMITTED this 16th day of March, 2005.

GALLAGHER & KENNEDY, P.A.

By Michael M. Grant

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10421-36/15169-6/1257893

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0528

REBUTTAL TESTIMONY OF

DIRK MINSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

MARCH 16, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Dirk Minson. I am the Chief Financial Officer of the Arizona Electric Power Cooperative, Inc. ("AEPCO") and my business address is 1000 South Highway 80, Benson, Arizona 85602.

Q. Did you file direct testimony in this matter?

A. Yes. I submitted direct testimony in support of AEPCO's rate application which was filed with the Commission on July 23, 2003.

Q. What is the purpose of this testimony?

A. I will summarize AEPCO's rebuttal position as well as respond to certain issues discussed in the testimony of Ms. Brown, Mr. Ramirez and Ms. Keene. In that regard, Gary Pierson, our Manager of Financial Services, is also presenting rebuttal testimony. I'll also update the Commission on AEPCO's current financial status and the progress of our discussions with Class A member Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") concerning its request to become a partial requirements member of AEPCO.

UPDATE

Q. In your direct testimony, you discussed the fact that adjusted 2003 test year results had produced a net margin loss of $4.5 million and a DSCR of only .70, which is well below the RUS mortgage minimum requirement of 1.0. AEPCO expected another operating margin loss in 2004. Did that happen?

A. Unfortunately, yes. AEPCO's 2004 operating loss totaled $2.6 million. The loss would have been much greater but for a required reversal of a liability associated with non-member economy sales to certain California entities in 2001.

Q. What does this mean for AEPCO?

A. First, AEPCO is not in financial compliance under the terms of its mortgage as well as the requirements of the RUS rules, primarily 7 CFR 1710.114. As a result, AEPCO is required to notify RUS in writing of its non-compliance and develop a plan to achieve compliance on a prospective basis. The plan will have to be acceptable to the RUS Administrator. Short of that acceptance, AEPCO will be in technical default and will be unable to secure loan funds for capital improvements or possibly not be able to draw existing loan funds for capital expenses already incurred. This restriction will remain in force until remedial action satisfactory to RUS is taken, such as implementation of the new rates we propose. Second, unfortunately the 2004 results have further eroded AEPCO's equity position after more than ten years of positive performance had eliminated in excess of $51 million in negative equity. We estimate that our equity now stands at $10.9 million or 4.3% of assets. At the end of 2002, it had reached almost 7%. These developments emphasize the need for a rate order from the Commission as quickly as possible.

Q. Have these developments impacted AEPCO's approach to this rebuttal testimony?

A. Yes. We felt it would assist Staff, the Administrative Law Judge and the Commission in speeding further evaluation and action if we would narrow, to the maximum extent possible, the issues in dispute and simplify our recommendations concerning revenue recommendations, rates and procedures. Thus, as Mr. Pierson explains in greater detail, we have limited our focus to a few major adjustment issues. We disagree with Staff on several other adjustments, but if they don't materially impact AEPCO's financial health we have elected not to contest them.

Q. Please update the Commission on the status of SSVEC's request to become a partial requirements AEPCO member.

A. AEPCO and SSVEC have completed a draft partial-requirements agreement acceptable to them. The RUS must approve the transition and, while we have communicated regularly with RUS concerning it, we have received no firm indication on how long the RUS review will take. Because the RUS might request changes to the agreement, we think it best to delay formal submission to the Commission until that process is complete. When RUS' approval is secured, we'll make a formal filing with the Commission for approval of the SSVEC Partial Requirements Capacity and Energy Agreement and any required partial- and all-requirements rate changes associated with it.

SUMMARY OF REBUTTAL POSITION

Q. Mr. Minson, please summarize AEPCO's reaction to the Staff's testimony.

A. Although we have disagreements with Staff on certain issues and details, we think the Staff's analysis provides an excellent framework within which to structure an order which allows AEPCO adequate rates and an opportunity to improve its financial position. For example, Staff has recognized the need for and supports (1) a revenue requirements increase, (2) adequate margins to support future necessary borrowing and positive equity improvement and (3) a Fuel and Purchased Power Cost Adjustor ("FPPCA"). Staff also agrees that all of our utility plant is used and useful. Staff's basic positions on these issues are very constructive. We hope that our approach in response is equally constructive and will allow rapid progress toward entry of a final rate decision.

Q. Please summarize AEPCO's revised requests.

A. Mr. Pierson provides greater detail on our positions. But, to summarize, we request that the Commission authorize: (1) an increase in operating revenues of approximately $9.446 million and a rate of return on rate base of 10.50%; (2) rates as set forth in Exhibit GEP-4; (3) an FPPCA; and (4) revised depreciation rates as set forth in Exhibit DCM-1. For convenience, I have attached as Exhibit DCM-3 proposed tariffs which reflect these requests and also include a proposed adjustor clause. It's important to stress that this will be the first rate increase for AEPCO since 1984. Indeed, in the past 20 years, AEPCO's rates to its member distribution cooperatives have declined approximately 22%. Thus, taking into account the generation and transmission rate requests, the average Class A member rates will still be about 17% <u>below</u> what they were in 1985.

COMMENTS ON SPECIFIC STAFF TESTIMONY

<u>Ms. Brown's Testimony</u>

Q. At page 4 of her testimony, Ms. Brown makes reference to a few customer comments received by the Commission on the rate application. Did you examine those materials?

A. Yes, I did. I think most of the concerns expressed grow out of a misunderstanding at the retail level of the impact of these <u>wholesale</u> rate requests by AEPCO as to generation and Southwest Transmission Cooperative, Inc. ("SWTC") as to transmission service. The Notice of Hearing which AEPCO and SWTC published and also circulated widely in member newsletters correctly stated that AEPCO and SWTC were requesting a combined approximately 24% revenue increase. A retail consumer reading that understandably assumes that means the end-use bill will increase 24% when, of course, that is not the case. Based on our revised rebuttal positions, we estimate that the average residential consumer would see approximately a $3.30 monthly increase attributable to AEPCO's generation case and a $1.45 monthly increase attributable to SWTC's transmission service case. We don't minimize any increase and our 20-year record of rate reductions reinforces that. But, I hope that provides additional context to evaluate the handful of comments which have been received.

Q. Please comment on Ms. Brown's testimony at pages 37-40 concerning redactions of executive session Board minutes and legal invoices.

A. In an effort to narrow issues in dispute, we are not objecting to Ms. Brown's adjustment. However, I do want to state the justifiable reasons for our redactions. Both before and after filing, we supplied Staff with a tremendous amount of data and documents. Multiple copies of about 16 bankers boxes of material were delivered in response to more than 150 Staff data requests. The materials included all Board regular and executive session minutes together with all legal invoices for a three-year period.

Q. What were the redactions?

A. Attorney discussions with the Board were redacted from executive session minutes and narrative descriptions were initially detached from legal invoices to avoid any waiver of the attorney-client privilege. Following discussions between our counsel and Staff's attorneys, it was agreed that the attorney narrative descriptions would be supplied with only minor redactions of entities which revealed specific privileged communications. Thus, Staff was supplied with both matter and amount descriptions and, depending upon how the firms reported their time, detailed descriptions of individual tasks performed. We thought this had satisfactorily resolved this issue.

Q. Is it important to protect the attorney-client privilege?

A. Yes. While I am not an attorney, I'm told that the attorney-client privilege cannot be selectively waived. Many of these matters involve ongoing litigation, other disputes which may result in suits, contract negotiations and similar legal matters which have very real cost and other impacts on AEPCO and the members we serve. If privileged information is released to Staff and then adverse parties learn of the release, they can demand access to our privileged discussions and attorneys' strategic advice. By way of example, as the Commission knows, AEPCO has been deeply involved in a Surface Transportation Board ("STB") rate case for several years. The result of the STB action will determine AEPCO's annual cost to transport approximately 1.5 million tons of coal. If the railroads had access to privileged information, AEPCO would be at a substantial disadvantage in that rate case. We hope the Commission agrees that result would not be in our member/consumers' best interests.

Q. Does AEPCO object to Ms. Brown's proposed $159,891 reduction in expenses attributable to food and similar expenses at page 41 and Schedules CSB-12 and CSB-22 of her testimony?

A. Again, in an effort to narrow disputed issues, we do not. However, many of the expenses are necessary to provide safe, reliable and adequate service. For example, the food expense was primarily for annual Member Meetings, employee training sessions and employee recruitment. The award expense was for employee safety awards. The lobbying expenses are percentage estimates of the total membership dues paid to the National Rural Electric Cooperative Association ("NRECA") and the Grand Canyon Electric Cooperative Association ("Grand Canyon") concerning the time both spend on lobbying. Federally, one of the NRECA's primary annual efforts is to try to assure adequate RUS/FFB loan funds for cooperatives—an obviously critical issue to our efforts to provide low-cost, reliable service. In Arizona, Grand Canyon monitors and, where necessary, advocates in relation to a number of legislative issues which directly impact cooperatives' cost and service abilities including property tax and other legislative proposals.

Q. Does AEPCO agree with Ms. Brown's recommendation at pages 43-44 of her testimony that the approximately $9.5 million in Commission-authorized legal and pension expense deferrals not be included in rates?

A. Yes. We had looked at that issue prior to filing and decided not to seek rate recovery. Because we were able to meet the expenses, but still hold down rates and build equity over the deferral period, we did not want to pass that $9.5 million in expenses through to our members.

Q. Finally, please comment on Ms. Brown's recommendation at pages 44-45 that AEPCO be required to separate the revenues and expenses for Anza in future rate filings.

A. We do not support the recommendation. Anza has been a Class A member of AEPCO since 1979. The Commission has never required in any of our previous cases a separate cost of service study for it. Anza's load was 1.5% of our total energy sales in 2003. Cost of service differences for Anza, if any, would be *de minimis* and would not justify either our expense in performing such a study, nor the Staff and Commission effort required to evaluate it.

Mr. Ramirez' Testimony

Q. Mr. Minson, at page 7 of his testimony, Mr. Ramirez expresses concern that AEPCO's proposed revenues as adjusted by Staff would not be sufficient to service its debt obligations. Do you agree?

A. Yes. That is why we are recommending that the revenue levels approved by the Commission be sufficient to produce the 1.05 DSCR level which our Board of Directors approved and we requested in our filing. Consistent with Mr. Ramirez' testimony, our recommendations will allow us to cover our debt service obligations and support additional debt financing which is necessary to meet service reliability and adequacy needs.

Q. Do you disagree with Mr. Ramirez' recommendation that AEPCO continue to improve its equity position?

A. Not at all. The rates that we propose would generate $8.2 million in net margins on an annual basis. Absent other changes, this level of margins would build AEPCO's equity ratio to 30% in about eight years.

Q. Do you have anything else to add in response to Mr. Ramirez' testimony?

A. Yes. I'd like to comment briefly on (1) his recommended target capital structure of 30% and (2) his recommendation that the Commission restrict future patronage distributions until 30% equity has been achieved.

Q. Please do so.

A. First, we strongly agree that AEPCO should continue to build equity and our record over the past 15 years demonstrates that. Following economic events of the 1980s which were beyond our control, such as a recession and losses of 125 MW in copper mining loads (about 25% of Apache Station's then total generating capacity), from 1991 to 2002 AEPCO's equity as a percentage of assets increased from a negative 14.9% to a positive 7%. Notably, we accomplished this substantial equity improvement through a variety of measures, including aggressive cost control, while simultaneously reducing member rates by 22% after 1986. We do not agree, however, that the Commission should establish 30% or any other firm percentage as a target equity goal in this decision.

Q. Why not?

A. For a number of reasons. First, as the past 20 years amply demonstrate, economic, financial and other conditions change. Locking in a target number unnecessarily binds both AEPCO and future Commissions' ability to react to those changes. For example, changes in environmental regulations impacting the timing and amount of necessary capital improvements are very difficult to predict. Second, balancing the sometimes competing goals of building equity, but also controlling member rates is an ongoing process requiring constant evaluation which is inconsistent with a fixed target. Third, moving to higher rates simply to keep pace with a predetermined equity goal may defeat the purpose. For example, increasing rates at the wrong time economically may, in fact, produce lower revenues and reduced margins. Finally, in my opinion, the 30% target is simply too high. Mr. Ramirez' Schedule AXR-2 demonstrates that. Only two of the 13 rated cooperatives listed have patronage equity levels above 30%. The rest range from roughly 26% to as low as 8%. The average is only 19%, which is consistent with an R.W. Beck 2002 survey which indicated that, of G&T cooperatives surveyed which had an equity ratio goal, the median goal was 17.5%. For all of these reasons, we recommend that the Commission not order an improvement in AEPCO's equity position to 30%.

Q. What's your response to Mr. Ramirez' recommendation that future patronage distributions by AEPCO be restricted until it has achieved a 30% capital structure?

A. Initially, let me clearly state that AEPCO has no plans for the foreseeable future to make any patronage distributions. As Mr. Ramirez notes, we already have RUS and CFC mortgage restrictions which control us in that regard and we see no reason for the Commission to act in this area. However, if the Commission wants to impose a patronage distribution restriction, we would ask that it simply order compliance by AEPCO with its mortgage restrictions.

Ms. Keene's Testimony

Q. Ms Keene recommends that the Commission authorize an FPPCA as requested by AEPCO. Do you have any comments on that recommendation?

A. Yes. We appreciate Staff's support of the concept and feel it will help considerably in stabilizing and improving AEPCO's financial position. We disagree only with Ms. Keene's recommendation to include in the FPPCA all revenue from non-Class A sales as an offset to costs in the clause.

Q. Why?

A. We do not support that suggestion for several reasons. We do propose to credit to the clause and the members' benefit any fuel costs recovered through non-Class A member economy sales. So, our disagreement is only over crediting the FPPCA with the margins received from those sales. The primary reason why is that a credit would actually result in a double recovery of these margins. All margins received from such sales in the test year have already been credited to reduce the members' cost of service in the rates we are requesting here. So, for example, more than $2.2 million in margins from economy sales in the test year have already been applied to reduce the members' cost of service and, therefore, the rates we are requesting here (Filing Schedule G-6, p. 2). If the margins from future economy sales are also credited to members through the FPPCA, the members will recover those margins twice. Second, crediting margins from economy sales also will distort the true price signal concerning fuel and purchase power costs sent to the members through the adjustor. Finally, margins from <u>non-member</u> economy sales are a primary way AEPCO can build equity with funds which don't have to be supplied by the members and their retail consumers. This enhances financial stability and also increases equity which the members and their member/consumers do not have to supply. Including those margins in the FPPCA would remove that source of margins. It would actively work against our attempts to gradually build equity which are supported by Staff.

Q. Does the Cooperative agree with Ms. Keene's proposal at pages 8-14 of her testimony to establish a Demand Side Management ("DSM") program for AEPCO?

A. No, it does not. AEPCO supports the efficient use and conservation of energy and is participating in the DSM evaluation effort currently ongoing at the Commission. However, as we have stated there, it is not appropriate as a wholesale generator for AEPCO to have a DSM program for several reasons. First, DSM programs are designed to affect end-use energy consumption. All of AEPCO's customers are distribution cooperatives that purchase wholesale electricity to supply at retail. DSM programs should be developed, delivered and financed by the local distribution cooperative, not the wholesale generator. Second, in addition to the distribution cooperative, if AEPCO were also required to provide DSM programs there would likely be a great deal of confusion by the end-use customer and a duplication of administrative costs. To require AEPCO to have a DSM program on top of the programs of its distribution cooperatives is akin to requiring the generation divisions and distribution divisions of APS or TEP to have separate DSM programs for the same set of retail customers or requiring the wholesale energy suppliers of UniSource Energy Services to provide a DSM program for the customers of UES. These programs are simply better left to the "retail" arm of the utility to maximize the opportunity for successful implementation. Finally, there is wide geographic, climate, economic and size diversity among the distribution cooperatives served by AEPCO. In addition, this diversity now includes the partial-requirement nature of one and soon to be two of our distribution cooperatives. This diversity creates the need for different DSM programs or, at the very least, variations in DSM programs depending on the need and opportunities in each service area. While AEPCO stands ready to assist our members in developing DSM programs, these differing needs can best be addressed and managed by the individual distribution cooperatives.

REVISED DEPRECIATION RATES

Q. Mr. Minson, please comment on AEPCO's request that the Commission approve revised, lower depreciation rates.

A. Staff did not directly address that subject in its testimony, but I assume that was just an oversight. I discussed the request in my direct testimony and would ask that the Commission approve the new lower rates as set forth in Exhibit DCM-1.

CONCLUSION

Q. Mr. Minson, please summarize AEPCO's requests.

A. We would request that the Commission approve the rates and FPPCA as set forth in Exhibit DCM-3 and revised, lower depreciation rates as set forth in Exhibit DCM-1. We would also ask that a proposed opinion be forwarded to the Commission for final approval as soon as possible.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

10421-36/1255529v2

EXHIBIT DCM-3

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

TARIFF

PERMANENT

Effective Date: ____________________

AVAILABILITY

Available to all cooperative associations which are or shall be all requirements Class A members of the Arizona Electric Power Cooperative, Inc. ("AEPCO").

MONTHLY RATE (BILLING PERIOD)

Electric power and energy furnished under this tariff will be subject to the following rates and terms:

> Demand Charge
> $13.98 per kW of billing demand, plus
>
> Energy Charge
> $0.02073 per kWh used during billing period, plus
>
> Base Power Cost Adjustor
> $0.00000 per kWh used during billing period

Billing Demand – The billing demand shall be that thirty minute integrated Class A member metered demand coincident at the hour of the AEPCO monthly peak. Contracts specifying demand levels and billing parameters are not included in this Class A member definition of billing demand and are billed separately.

Billing Month – The first calendar month preceding the month the bill is rendered.

Additional Charges – Service is also subject to the rates and charges stated in AEPCO's Regulatory Assets and Competition Transition Charge Supplemental Tariff. The demand and energy rates stated herein include no allowance for recovery of regulatory assets. Pursuant to Decision No. 62758, the regulatory assets and RAC have been assigned to Southwest Transmission Cooperative, Inc. AEPCO will pass through to its Class A members the RAC assessed by Southwest Transmission Cooperative, Inc.

Power Factor – Each member shall maintain power factor at the time of maximum demand as close to unity as possible. In the event the power factor measured at the time of the maximum demand is less than 95% lagging or leading, the maximum demand shall be adjusted for billing purposes by dividing the maximum measured demand by the measured power factor multiplied by .95. The provisions of the power factor adjustment will be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Taxes – Bills rendered are also subject to adjustment for all federal, state and local government taxes or levies on such sales and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Transmission and Ancillary Service Charges – Each Class A member will also be billed by AEPCO for charges it incurs for the transmission of energy to the Class A member's delivery point(s). Such charges will be assessed to the Class A member at the rates actually charged AEPCO by the transmission provider and others for transmission service and the provision of ancillary services.

Base Power Cost Adjustor - The monthly bill computed under this schedule will, on the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh used by the Adjustor where:

F = (PC + BA) - $0.01777

F = Adjustment factor in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

PC = The Commission allowed pro forma fuel, purchased power and wheeling costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BA = The "Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over or under collected in the past.

Allowable fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's own plants as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis. Included therein may be such costs as that charged for economy energy purchases and the charges as a result of scheduled outage. All such kinds of energy being purchased by AEPCO to substitute for its own higher cost energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of energy as recorded in RUS Account 565 and less

E. The demand and energy costs recovered through non-tariff contractual firm sales of power and energy as recorded in RUS Account 447, less

F. The energy costs recovered through inter-system sales including the incremental fuel and/or purchased energy costs related to economy energy sales and other energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Base Power Cost Adjustor as specified herein based upon a rolling twelve month average and file on September 1 or March 1 of the month preceding the effective date of the Base Power Cost Adjustor (i.e., October 1 or April 1): (1) calculations supporting the revised Adjustor with the Director, Utilities Division and (2) a tariff reflecting the revised Adjustor with the Commission which shall be effective for billings after the 1st day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

10421-36/1257338

Arizona Electric Power Cooperative, Inc.

Partial Requirements Member
Rates and Fixed Charge
(Effective as of ____________)

<u>Fixed Charge</u>

Mohave Electric Cooperative, Inc.	$761,245 per month
<u>O&M Rate</u>	$7.07 per kW/month
<u>Energy Rate</u>	$0.02073 per kWh used during the billing period
<u>Base Power Cost Adjustor</u>	$0.00000 per kWh used during billing period

<u>Base Power Cost Adjustor</u> - The monthly bill computed under this schedule will on the procedures stated herein be increased or decreased by an amount equal to the result of multiplying the kWh used by the Adjustor where:

F = (PC + BA) - $0.01694

F = Adjustment factor in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

PC = The Commission allowed pro forma fuel, purchased power and wheeling costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BA = The "Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over or under collected in the past.

Allowable fuel, purchased power and wheeling costs include:

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C. The cost of energy purchased when such energy is purchased on an economic dispatch basis. Included therein may be such costs as that charged for economy energy purchases and the charges as a result of scheduled outage. All such kinds of energy being purchased by AEPCO to substitute for its own higher cost energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of energy as recorded in RUS Account 565 and less

E. The demand and energy costs recovered through non-tariff contractual firm sales of power and energy as recorded in RUS Account 447, less

F. The energy costs recovered through inter-system sales including the incremental fuel and/or purchased energy costs related to economy energy sales and other energy sold on an economic dispatch basis as recorded in RUS Account 447.

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10421-36/1256863

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0528

REBUTTAL TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

MARCH 16, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored direct testimony for the Arizona Electric Power Cooperative, Inc. ("AEPCO") in this matter?

A. Yes, I am.

Q. Have you reviewed the direct testimony of Staff witnesses Crystal Brown, Barbara Keene, Alejandro Ramirez and Jerry Smith filed February 23, 2005 in this matter?

A. Yes, I have. As Mr. Minson discusses in his testimony, in order to narrow the issues in dispute and reduce complexity, for rebuttal purposes AEPCO accepts all seven of the Rate Base Adjustments proposed by Ms. Brown at pages 8-22 of her testimony. Further, AEPCO accepts nine of the twelve Operating Income Adjustments proposed by Ms. Brown as follows:

Adjustment No 1 – PTY Revenue and Expense	Schedule CSB-13
Adjustment No 3 – Asset Retirement Obligation	Schedule CSB-15
Adjustment No 6 – Transmission Expense Annualization	Schedule CSB-18
Adjustment No 7 – Normalized Legal Expense	Schedule CSB-19
Adjustment No 8 – Fuel Expense	Schedule CSB-20
Adjustment No 9 – Advertising Expense	Schedule CSB-21
Adjustment No 10 – Contributions & Other Expenses	Schedule CSB-22
Adjustment No 11 – ACC Gross Revenue Assessment	Schedule CSB-23
Adjustment No 12 – Interest on Long Term Debt	Schedule CSB-24

Thus, my rebuttal testimony will primarily address the remaining three proposed adjustments:

<u>Operating Income Adjustments</u>

Adjustment No 2 – Revenue and Expense Annualization	Schedule CSB-14
Adjustment No 4 – Tracker Mechanism (Base Power Cost)	Schedule CSB-16
Adjustment No 5 – Overhaul Accrual Expense	Schedule CSB-17

In addition, I am sponsoring Exhibits GEP-2 through GEP-10 in support of AEPCO's rebuttal position in this matter.

RATE BASE – AEPCO REBUTTAL POSITION

Q. Have you reviewed the Staff's testimony on the original cost/fair value rate base for this proceeding?

A. Yes, I have. As I indicated, AEPCO accepts the Staff's proposed rate base of $189,637,810 for purposes of determining its fair value rate base.

OPERATING INCOME – AEPCO REBUTTAL POSITION

Q. Please summarize AEPCO's rebuttal position based upon the Staff's direct testimony.

A. As shown on Exhibits GEP-5, column D and GEP-6, AEPCO proposes test year revenues of $138,951,691 and expenses of $128,494,283. This produces operating margins before interest on long-term debt of $10,457,408 and a net margin loss of $1,235,695. As I'll explain, the test year revenues we propose are $336,455 less than the Staff's position and the expenses are $187,911 greater. Thus, the operating margins before interest on long-term debt and the net margin loss amounts are $524,366 lower in our rebuttal position. The three rebuttal adjustments we propose and my exhibits which explain them are:

Adjustment No 1 – Revenue and Expense Annualization	Exhibit GEP-7
Adjustment No 2 – Overhaul Accrual Expense	Exhibit GEP-8
Adjustment No 3 – Tracker Mechanism (Base Power Cost)	Exhibit GEP-9

Rebuttal Adjustment No. 1 – Revenue and Expense Annualization

Q. Please describe the growth adjustment which is proposed by Ms. Brown to AEPCO's revenues and expenses.

A. Ms. Brown made a growth annualization adjustment in order to achieve a matching of revenues and expenses with the year-end rate base (Brown Testimony, pp. 25-26). Staff computed the adjustment by applying one-half of the customer load growth percentage of AEPCO's Class A Members or 1.65% to the demand and energy revenues as well as the variable expenses. As a result, Staff proposes an increase in revenues of $1,271,908 and an increase in expenses of $264,376.

Q. Please describe the Company's position on the growth adjustment.

A. We will not object to the concept, but Ms. Brown's adjustment does not take into account the fact that Mohave Electric Cooperative, Inc. ("Mohave") is a partial requirements customer of AEPCO. As such, its customer load growth does not result in increased power deliveries by and increased revenues to AEPCO. Therefore, the adjustment is somewhat overstated due to the inclusion of Mohave's test year customer load growth.

Q. Have you prepared an exhibit which explains AEPCO's rebuttal position?

A. Yes, I have. Exhibit GEP-7 takes Ms. Brown's adjustment, as set forth in her Schedule CSB-14, and modifies it by excluding Mohave's customer growth for 2003 from the calculation of the annualization factor. That decreases the factor from 1.65% to 1.61%. Our adjustment reduces the Staff proposed revenue adjustment by $336,455 and the Staff proposed expense adjustment by $5,658.

<u>Rebuttal Adjustment No. 2 – Overhaul Accrual Expense</u>

Q. Please describe the adjustment which Ms. Brown proposes to overhaul accrual expense at pages 31-32 of her testimony.

A. Staff proposes an adjustment to reflect overhaul accrual expense based upon an eight-year historic average of overhaul cost incurred during the years 1996 through 2003. Staff proposes a reduction of $657,788, which decreases the total expense to $4,129,720.

Q. What is AEPCO's position on this adjustment?

A. While we are confident that our overhaul accruals method is and will be representative of our experience, in order to reduce issues in dispute, we will not object to Staff's alternate approach. However, Ms. Brown's adjustment does not provide an adequate accrual for a Gas Turbine 4 major overhaul. Gas Turbine 4 is a 38 MW aero-derivative combustion turbine that was very recently placed into commercial service in October 2002. Therefore, it was not in service for almost all of the historic 1996-2003 period. In September 2003, it was determined, based upon operating characteristics, that a major overhaul of Gas Turbine 4 will be required in October 2010. Based upon engineering estimates of the cost of that major overhaul, AEPCO began accruing approximately $19,000 per month starting October 2003 based upon the remaining 84 months of the eight-year cycle. However, only $57,354 of expense, as shown on Schedule CSB-17, line 10, would be accrued for a Gas Turbine 4 overhaul based upon Ms. Brown's historic approach. That obviously will not adequately cover the $1.6 million cost of the overhaul.

Q. Have you prepared an adjustment setting forth AEPCO's rebuttal position?

A. Yes, I have. Exhibit GEP-8 takes Ms. Brown's adjustment and modifies it by incorporating an adjustment to recognize the monthly accrual for the Gas Turbine 4 major overhaul which began in the test year. An annual accrual in the amount of $200,738 ($1,605,900/8 years) for Gas Turbine 4 less the amount included in the Staff's adjustment of $7,169 ($57,354/8 years) should be added to Staff's proposed adjustment. As shown on line 16, this increases the Staff proposed adjustment by $193,569.

Rebuttal Adjustment No. 3 – Tracker Mechanism (Base Power Cost)

Q. Please describe Ms. Brown's adjustment in relation to AEPCO's Base Power Cost at pages 29-30 of her testimony.

A. Ms. Brown takes AEPCO's filed position on the base cost of power of $41,276,155 and reduces it by $7,716,227 which lowers the adjustor base rate from $0.02038/kWh to $0.01657/kWh.

Q. Please describe the Company's position on the adjustments contained in Schedule CSB-16.

A. The company accepts the fuel expense adjustment that Ms. Brown made to column B, l. 11 of Schedule CSB-16, but does not accept the purchased power adjustment set forth in column B, l. 27. The Staff adjustment "annualizing savings from a new contract that was in effect for only half of the test year" is not a reduction in the purchased power <u>energy</u> costs of the Public Service Company of New Mexico ("PNM") (Direct Testimony of Ms. Brown, p. 30, ll. 21-22). Rather, the adjustment is an annualization of the payment for a 2 MW contract <u>demand</u> reduction in the AEPCO/PNM contract. Therefore, it should not be deducted from the purchased power <u>energy</u> costs of PNM. To clarify, we agree with Staff's proposed adjustment of $250,000, but the adjustment should be made against purchased power demand costs, not purchased power energy costs. In addition to the fuel expense and purchased power adjustment, Ms. Brown has also made adjustments to add certain fixed fuel costs, purchased/demand costs, firm wheeling expenses and credits for non-tariff sales fuel recovery/demand based upon the recommendations of Ms. Keene. AEPCO agrees to including the gas reservation charges, demand charges for purchased power, firm wheeling costs and certain credits for non-tariff sales fuel recovery. But, as explained in Mr. Minson's rebuttal testimony, AEPCO does not agree that revenue credits reflecting the margins on economy energy sales should be included in the determination of the base power cost and adjustor base rate.

Q. Have you prepared an adjustment setting forth this position?

A. Yes, I have. Exhibit GEP-9, page 1 makes certain adjustments to Ms. Brown's Schedule CSB-16 to reflect our rebuttal position. Column [D] sets forth these rebuttal adjustments. On line 5, test year sales are adjusted to reflect the energy billing units associated with the revenue annualization that the Company proposed in Schedule GEP-6. Line 27 removes the Staff adjustment to reduce PNM purchased power energy costs that should be made instead to PNM purchased power demand costs. Line 31 correspondingly adds the Staff adjustment to reduce PNM purchased power demand costs. Line 51 removes the $2,215,834 in margins associated with economy energy sales from the Staff adjustment for the non-tariff demand related revenues. As a result of these adjustments, the base cost of power should be $35,776,234, which translates to an adjustor base of $0.01748/kWh as shown on line 6, page 2 of Exhibit GEP-9.

Q. Are there any further modifications to the base power costs determination that AEPCO is proposing?

A. Yes. There are certain purchased demand costs and wheeling costs that are applicable to our all-requirements members, but are not applicable to our partial-requirements member Mohave. These costs represent purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement that Mohave elected not to participate in. These costs have been excluded from the calculation of Mohave's fixed charge and operations and maintenance rate and should be excluded as well from Mohave's base cost of power. Page 2, line 6 of Exhibit GEP-9 shows this differential calculation of the base power cost for the all-requirement and partial-requirement members. Therefore, AEPCO recommends that the all-requirements adjustor base be set at $0.01777/kWh and that the partial-requirements adjustor base be set at $0.01694/kWh.

REBUTTAL POSITION – REVENUE REQUIREMENTS AND RATES

Q. Please state the Company's rebuttal position on revenue requirements and rates.

A. The Board of Directors instructed AEPCO to seek Commission approval for revised rates designed to achieve a 2003 test year result equal to a Debt Service Coverage Ratio ("DSCR") of 1.05. A copy of this resolution, adopted on July 14, 2004, is attached as Exhibit GEP-10. The Board of Directors determined that this level of increase was necessary to ensure that AEPCO satisfies its mortgage requirements and maintains a satisfactory level of financial integrity while simultaneously building cooperative equity. As Mr. Ramirez notes in his testimony at page 2, the Staff's minimum recommended operating income would produce a DSCR of only .91, which is below RUS minimum requirement. We agree with his statements at page 7 of his testimony that this level of revenue would not be sufficient to service current debt, build equity or support new debt financing. Therefore, applying the 1.05 DSCR to AEPCO's proposed test year revenues of $138,951,691, expenses of $128,494,283, operating margins before interest on long-term debt of $10,457,408 and the net margin loss of $1,235,695, operating revenues should be increased by $9,446,032 as shown in column E, Exhibit GEP-5.

Q. Have you prepared exhibits which summarize AEPCO's rebuttal position?

A. Yes. Exhibit GEP-2 sets forth AEPCO's rebuttal position in column [C]. We request that the Commission enter its order approving an increase of $9,446,032 in operating revenue and a rate of return of 10.50% on the fair value rate base of $189,637,810. Exhibit GEP-3 is the rate base summary. Exhibit GEP-4 sets forth the proposed rates based on AEPCO's rebuttal position in column [C]. Exhibit GEP-5 summarizes

Operating Income – Test Year. Finally, Exhibit GEP-6 sets forth our rebuttal adjustments to the Staff's Test Year – As Adjusted.

Q. Why are the rebuttal rates requested in column C of Exhibit GEP-4 higher than those originally requested in AEPCO's filing?

A. Primarily because in preparing our original schedules, the fourth quarter 2003 test year debt principle payment in the approximate amount of $2.2 million was overlooked. AEPCO had attempted to make the payment on December 31, 2003, but the wire transfer to the U.S. Treasury failed. It was successfully made on the first business day of 2004, but several months later when the rate case schedules were being prepared, the fact that the payment was attributable to the 2003 test year was overlooked. Taking this payment into account, the original rate request should have been approximately $2.3 million higher to cover the principle payment and the 1.05 DSCR associated with it.

Q. How was this omission discovered?

A. We learned of it in early January 2005 while researching the answer to a Staff data request. We promptly advised Staff of the situation. In February, we also discussed the matter and the fact that the original rate request should have been higher with the AEPCO Board of Directors.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

10421-36/1257424

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-2**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL FILING		[B] STAFF DIRECT POSITION		[C] COMPANY REBUTTAL POSITION
1	Adjusted Operating Income (Loss)	$	7,972,676	$	10,981,774	$	10,457,408
2	Depreciation and Amortization	$	7,608,735	$	7,539,289	$	7,539,289
3	Income Tax Expense		-		-		-
4	Long-term Interest Expense	$	13,547,749	$	13,313,164	$	13,313,164
5	Principal Repayment	$	10,344,950	$	14,360,494	$	14,360,494
6a	Recommended Increase in Operating Revenue	$	8,450,016	$	6,773,320	$	9,446,032
6b	Percent Increase (Line 6a / Line 7b) - Per Staff		N/A		4.86%		6.80%
6c	Percent Increase (Line 6a / Line 7a) - Per Coop		9.86%		7.80%		10.92%
7a	Adjusted Class A Member Revenue	$	85,685,624	$	86,810,386	$	86,473,931
7b	Adjusted Test Year Operating Revenue	$	137,611,450	$	139,288,146	$	138,951,691
8	Recommended Annual Operating Revenue	$	146,061,466	$	146,061,466	$	148,397,723
9a	Recommended Operating Margin Before Interest	$	16,422,692	$	17,755,094	$	19,903,440
9b	Recommended Margins(Loss) After Interest	$	1,959,955	$	4,099,540	$	6,247,886
9c	Recommended Net Margin	$	3,922,406	$	6,061,991	$	8,210,337
10a	Staff TIER (L3+L9a)/L4 - Per Staff		N/A		1.33		1.50
10b	TIER (L9c+L4)/L4 - Per Coop (RUS Definition)		1.29		1.46		1.62
11a	Staff DSC (L2+L3+L9b)/(L4+L5) - Per Staff		N/A		0.91		0.99
11b	DSC (L2+L4+L9c)/(L4+L5) - Per Coop (RUS Definition)		1.05		0.97		1.05
12	Adjusted Rate Base	$	222,147,011	$	189,637,810	$	189,637,810
13	Rate of Return (L9a / L12)		7.39%		9.36%		10.50%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony Alejandro Ramirez
Column [C]: Exhibits GEP-3, GEP-5

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-3

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[C] STAFF DIRECT POSITION	[C] COMPANY REBUTTAL POSITION
1	Plant in Service	$ 389,603,749	$ 377,675,263	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(186,190,519)	(185,936,636)	(185,936,636)
3	Net Plant in Service	203,413,230	191,738,627	191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	-	-	-
5	Contributions in Aid of Construction (CIAC)	-	-	-
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	-	-	-
9	Member Advances	-	(11,982,081)	(11,982,081)
	ADD:			
10	Working Capital	16,778,408	9,881,264	9,881,264
11	Plant Held for Future Use	-	-	-
12	Deferred Debits	1,955,373	-	-
13	Total Rate Base	$ 222,147,011	$ 189,637,810	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Staff Schedule CSB-2, Column C
Column [C]: Rebuttal Testimony Gary Pierson

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-4**

Docket No. E-01773A-04-0528

Test Year Ended December 31, 2003

SUMMARY OF PROPOSED RATES

Line No.	Description	[A] Company Original Filing	[B] Staff Direct Position	[C] Company Rebuttal Position
1	All Requirements Members:			
2	Demand Rate - $/kW Month	$ 13.79	$ 12.90	$ 13.98
3	Energy Rate - $/kWh	$ 0.02071	$ 0.02079	$ 0.02073
4	Power Cost Adjustor Base - $/kWh	$ 0.02038	$ 0.01657	$ 0.01777
5	Partial Requirements Members:			
6	Fixed Charge - $/Month	$ 705,795	$ 707,392	$ 761,245
7	O&M Rate - $/kW Month	$ 7.25	$ 7.48	$ 7.07
8	Energy Rate - $/kWh	$ 0.02071	$ 0.02079	$ 0.02073
9	Power Cost Adjustor Base - $/kWh	$ 0.02038	$ 0.01657	$ 0.01694
10	Proposed Revenue Increase - ($000's):			
11	Anza	$ 147.9	$ 79.4	$ 167.5
12	Duncan Valley	90.1	47.5	101.2
13	Graham County	470.8	246.9	527.0
14	Mohave	4,001.3	4,421.2	4,432.9
15	Sulphur Springs	2,148.5	1,158.0	2,415.0
16	Trico	1,591.4	826.9	1,802.4
17	Total Class A	$ 8,450.0	$ 6,779.9	$ 9,446.0
18	Proposed Revenue Increase - Percent:			
19	Anza	7.73%	4.08%	8.60%
20	Duncan Valley	7.77%	4.07%	8.64%
21	Graham County	7.82%	4.07%	8.69%
22	Mohave	14.00%	15.30%	15.53%
23	Sulphur Springs	7.69%	4.09%	8.52%
24	Trico	7.94%	4.05%	8.83%
25	Total Class A	9.86%	7.81%	10.92%

References:

Column A - Company Original Filing, Schedules G2A & H-2
Column B - Staff Witness Keene Testimony and Workpapers
Column C - Gary Pierson Rebuttal Testimony and Workpapers

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-5

OPERATING INCOME - TEST YEAR, STAFF ADJUSTED AND COMPANY PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR AS ADJUSTED	[C] COMPANY REBUTTAL TEST YEAR ADJUSTMENTS	[D] COMPANY REBUTTAL TEST YEAR AS ADJUSTED	[E] COMPANY REBUTTAL PROPOSED CHANGES	[F] COMPANY REBUTTAL RECOMMENDED
	REVENUES:						
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ 37,818,004	$ 12,879,693	$ 50,697,697	$ 9,446,032	$ 60,143,729
2	Class A Members, Base Cost of Power Revenue	41,276,155	48,992,382	(13,216,148)	35,776,234		35,776,234
3	Total Class A Member Electric Revenue	85,685,624	86,810,386	(336,455)	86,473,931	9,446,032	95,919,963
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	50,996,438	-	50,996,438	-	50,996,438
5	Total Electric Revenue	136,130,128	137,806,824	(336,455)	137,470,369	9,446,032	146,916,401
6	Other Operating Revenue	1,481,322	1,481,322	-	1,481,322	-	1,481,322
7	Total Revenues	137,611,450	139,288,146	(336,455)	138,951,691	9,446,032	148,397,723
	EXPENSES:						
8	Operations - Production, Fuel	59,803,425	59,014,728	(264,376)	58,750,352	-	58,750,352
9	Operations - Production, Steam	8,764,555	8,764,555	258,718	9,023,273	-	9,023,273
10	Operations - Production, Other	1,335,333	1,743,316	-	1,743,316	-	1,743,316
11	Operations - Other Pwr Supply, Demand	5,769,587	5,769,587	(250,000)	5,519,587	-	5,519,587
12	Operations - Other Pwr Supply - Energy	12,420,888	12,170,888	250,000	12,420,888	-	12,420,888
13	Operations - Transmission	8,036,486	8,036,486	-	8,036,486	-	8,036,486
14	Operations - Administrative and General	9,191,902	9,525,759	-	9,525,759	-	9,525,759
15	Maintenance - Production, Steam	10,170,045	9,512,258	193,569	9,705,827	-	9,705,827
16	Maintenance - Production, Other	2,809,881	2,809,881	-	2,809,881	-	2,809,881
17	Maintenance - Transmission	28,388	8,828	-	8,828	-	8,828
18	Maintenance - General Plant	63,958	63,958	-	63,958	-	63,958
19	Depreciation and Amortization	7,608,735	7,539,289	-	7,539,289	-	7,539,289
20	ACC Gross Revenue Taxes	288,752	-	-	-	-	-
21	Taxes	3,346,839	3,346,839	-	3,346,839	-	3,346,839
22	Total Operating Expenses	129,638,774	128,306,372	187,911	128,494,283	-	128,494,283
23	Operating Margin Before Interest on L.T.- Debt	7,972,676	10,981,774	(524,366)	10,457,408	9,446,032	19,903,440
24	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS:*						
25	Interest on Long-term Debt	13,547,749	13,313,164	-	13,313,164	-	13,313,164
26	Other Interest & Other Deductions	914,988	342,390	-	342,390	-	342,390
27	Total Interest & Other Deductions	14,462,737	13,655,554	-	13,655,554	-	13,655,554
28	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(6,490,061)	(2,673,780)	(524,366)	(3,198,146)	9,446,032	6,247,886
29	*NON-OPERATING MARGINS*						
30	Interest Income	582,014	582,014	-	582,014	-	582,014
31	Other Non-operating Income	1,380,437	1,380,437	-	1,380,437	-	1,380,437
32	Total Non-Operating Margins	1,962,451	1,962,451	-	1,962,451	-	1,962,451
33	*EXTRAORDINARY ITEMS*	-	-	-	-	-	-
34	*NET MARGINS (LOSS)*	$ (4,527,610)	$ (711,329)	$ (524,366)	$ (1,235,695)	$ 9,446,032	$ 8,210,337

35 References:
36 Column [A]: Cooperative Schedule C-1, Pages 1 and 2
37 Column [B]: Schedule CSB-11, Column C
38 Column [C]: Exhibit GEP-5

References:
Column [D]: Column [B] + Column [C]
Column [E]: Exhibit GEP-2
Column [F]: Column [D] + Column [E]

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-6**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] STAFF TEST YEAR AS Adjusted	[B] ADJ #1 Revenue and Expense Annualizations Ref: Sch GEP-7	[C] ADJ #2 Overhaul Accrual Expense Ref: Sch GEP-8	[D] ADJ #3 Tracker Mechanism (Base Power Cost) Ref: Sch GEP-9	[E] COMPANY REBUTTAL AS ADJUSTED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (336,455)	$ -	$ 13,216,148	$ 50,697,697
2	Class A Members, Base Cost of Power Revenue	48,992,382	-	-	(13,216,148)	35,776,234
3	Total Class A Member Electric Revenue	86,810,386	(336,455)	-	-	86,473,931
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	-	-	50,996,438
5	Total Electric Revenue	137,806,824	(336,455)	-	-	137,470,369
6	Other Operating Revenue	1,481,322	-	-	-	1,481,322
7	Total Revenues	139,288,146	(336,455)	-	-	138,951,691
8	*OPERATING EXPENSES:*					
9	Operations - Production, Fuel	59,014,728	(264,376)	-	-	58,750,352
10	Operations - Production, Steam	8,764,555 [1]	258,718	-	-	9,023,273
11	Operations - Production, Other	1,743,316 [2]		-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	5,769,587	-	-	(250,000)	5,519,587
13	Operations - Other Pwr Supply - Energy	12,170,888 [3]	-	-	250,000	12,420,888
14	Operations - Transmission	8,036,486	-	-	-	8,036,486
15	Operations - Administrative and General	9,525,759	-	-	-	9,525,759
16	Maintenance - Production, Steam	9,512,258 [4]	-	193,569	-	9,705,827
17	Maintenance - Production, Other	2,809,881	-	-	-	2,809,881
18	Maintenance - Transmission	8,828	-	-	-	8,828
19	Maintenance - General Plant	63,958	-	-	-	63,958
20	Depreciation and Amortization	7,539,289	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	3,346,839
23	Total Operating Expenses	128,306,372	(5,658)	193,569	-	128,494,283
24	Operating Margin Before Interest on L.T.- Debt	10,981,774	(330,797)	(193,569)	-	10,457,408
25	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*					
26	Interest on Long-term Debt	13,313,164	-	-	-	13,313,164
27	Other Interest & Other Deductions	342,390	-	-	-	342,390
28	Total Interest & Other Deductions	13,655,554	-	-	-	13,655,554
29	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(2,673,780)	(330,797)	(193,569)	-	(3,198,146)
30	*NON-OPERATING MARGINS*					
31	Interest Income	582,014	-	-	-	582,014
32	Other Non-operating Income	1,380,437	-	-	-	1,380,437
33	Total Non-Operating Margins	1,962,451	-	-	-	1,962,451
34	*EXTRAORDINARY ITEMS*	-	-	-	-	-
35	*NET MARGINS (LOSS)*	$ (711,329)	$ (330,797)	$ (193,569)	$ -	$ (1,235,695)

Footnote Explanations

[1] Includes account nos. 500, 5 Includes account nos. 555 to 557

[2] Includes account nos. 546, 5 Includes account nos. 510 to 515

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-7**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 1 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Class A Member Demand Revenues	$ 36,990,731	$ 6,922,455	$ 30,068,276
2	Class A Member Energy Revenues	$ 40,285,075	$ 14,260,705	$ 26,024,370
3	Class A Member ACC Assessment Rev	$ -	$ -	$ -
4	Class A Member Fixed Charge Revenues	$ -	$ -	$ -
5	Total Class A Member Base Rate Revenues	$ 77,275,806	$ 21,183,160	$ 56,092,646
6	Factor to Annualize Revenues to End of Test Year	1.65%		1.67%
7	Revenue Annualization Adjustment	$ 1,271,908	$ (336,455)	$ 935,453
8	Variable Expenses Not Recovered Through Fuel Adj	$ -		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
10	Adjustment to Expenses	$ 264,376	$ (5,658)	$ 258,718

LINE NO.		Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
11		Calculation of Annualization Factor						
12		Number of Customers						
13		Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
14	2002	3,702	2,446	7,481	N/A	43,113	27,631	84,373
15	2003	3,824	2,484	7,623	N/A	44,431	28,729	87,091
16	Increase	122	38	142	N/A	1,318	1,098	2,718
17	% Increase	3.30%	1.55%	1.90%	0.00%	3.06%	3.97%	3.22%
18	2003 Growth Rate							3.22%
19	Annualization Factor - 2003 Growth Rate divided by 2							
19a		1.65%	0.78%	0.95%	0.00%	1.53%	1.99%	1.61%

LINE NO.	Account No.	Description	Amount	
20		Calculation of Variable Expenses		
21		Not Recovered Through Fuel Adjustor		
22-23	Account No.	Description	Amount	
24	500	Operation Supervision and Engineering	$ 1,999,908	
25	501&547	Fuel - Steam Power & Other	$ 59,803,425	
26	502	Steam Expenses	$ 2,710,803	
27	505	Electric Expenses	$ 1,437,524	
28	510	Maintenance Supervision & Engineering	$ 840,774	
29	512	Maintenance of Boiler Plant	$ 6,433,681	
30	513	Maintenance of Electric Plant	$ 264,759	
31	514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
32	555	Purchased Power - Demand	$ 5,769,587	
33	555	Purchased Power - Energy	$ 10,085,538	
34		Total Variable Expenses	$ 91,720,960	
35	501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
36	555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
37	555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
38			$ 16,062,410	
39		2003 Growth Rate	1.61%	
40		Adjustment to Expenses	$ 258,718	

41 <u>References:</u>
42 Column A: Cooperative Data Request Response CSB 6-1
43 Column B: Testimony, CSB
44 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-8**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 3 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Overhaul Accrual Expense	$4,129,720	$ 193,569	$ 4,323,289

2		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 57,354	$ 3,206,259
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 57,354	$ 33,037,763
12								Divided by	8
13		ADJUSTMENT TO ANNUALIZE GT4 OVERHAUL ACCRUALS							$ 4,129,720
14		ANNUAL GT4 MAJOR OVERHAUL ACCRUAL - $1,605,900 / 8 YEARS =					$ 200,738		
15		LESS: AMOUNT INCLUDED IN TOTAL, LINE 10 - $57,354 / 8 YEARS=					7,169		
16		ADDITIONAL GT4 ACCRUAL							193,569
17									$ 4,323,289
18									

19 * *Per response to CSB 1-38, there has been no actual overhaul expense*
20 *for generating GT2 for the period 1990 to 2004.*

21 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.

22 References:

23 Column A: Staff Exhibit CSB -17, Column C
24 Column B: Gary Pierson Rebuttal Testimony
25 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	[D] COMPANY REBUTTAL ADJUSTMENTS	[E] COMPANY REBUTTAL AS ADJUSTED
1	Base Cost of Power Revenue					
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.01714	$ 0.00324	$ 0.02038	$ (0.00381)	$ 0.01657
4	Adjustment to match Coop proposed power expense to revenue	$ 34,714,097	$ 6,562,058	$ 41,276,155	$ (7,715,755)	$ 33,560,400
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533	21,063,927	2,046,390,460
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.02038	$ (0.00381)	$ 0.01657	$ 0.00091	$ 0.01748
7	Adjustment to reflect Staff's adjustments to power costs	$ 41,276,627	$ (7,716,227)	$ 33,560,400	$ 2,215,834	$ 35,776,234
8	Total	$ 34,714,097	$ (1,153,697)	$ 33,560,400	$ 2,215,834	$ 35,776,234
9	Base Cost of Power Expense					
10	Coal Fired Steam Plant Costs:					
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,029,531	$ 503,401	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-	-	-
14	Less: Fixed Fuel Costs	(549,137)	253,272	(295,865)	-	(295,865)
15	Subtotal	$ 43,789,748	$ 756,673	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:					
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809	-	9,809
19	Less: Fixed Fuel Costs	(1,435,208)	1,435,208	-	-	-
20	Subtotal	$ 14,029,332	$ 1,435,208	$ 15,464,540	$ -	$ 15,464,540
21	Total Fuel Costs	$ 57,819,080	$ 2,191,881	$ 60,010,961	$ -	$ 60,010,961
22	Purchased Power Energy Costs					
23	Firm Purchases					
24	CRSP	$ 309,547	$ -	$ 309,547	$ -	$ 309,547
25	PacifiCorp	-	-	-	-	-
26	Parker Davis	217,629	-	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061	(250,000)	1,713,061	250,000	1,963,061
28	Panda Gila River	1,134,573	-	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ (250,000)	$ 3,374,810	$ 250,000	$ 3,624,810
31	*Firm Purchases, Demand*	$ -	5,769,587	$ 5,769,587	(250,000)	5,519,587
32	Nonfirm Purchases, Demand and Energy	6,460,728	-	6,460,728	-	6,460,728
33	Total Purchased Power Costs	$ 10,085,538	$ 5,519,587	$ 15,605,125	$ -	$ 15,605,125
34	Firm Wheeling Expenses	$ -	7,939,635	$ 7,939,635	-	$ 7,939,635
35	Non-firm Wheeling Expenses	77,291	-	77,291	-	77,291
36	Total Firm and Non-Firm Wheeling Expenses	$ 77,291	$ 7,939,635	$ 8,016,926	$ -	$ 8,016,926
37	TOTAL FUEL COSTS & PURCHASED ENERGY	$ 67,981,909	$ 15,651,103	$ 83,633,012	$ -	$ 83,633,012
38	Less:					
39	Non-tariff Sales Fuel Recovery					
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-	-	-
42	City of Mesa (PSA)	2,657,351	(90,879)	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,376,189	(20,185)	1,356,004	-	1,356,004
44	SRP	13,039,105	(260,828)	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921	-	142,921
47	*Subtotal*	$ 18,311,016	$ (371,892)	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:					
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,705,282	$ (371,892)	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ -	$ 23,739,222	$ 23,739,222	$ (2,215,834)	$ 21,523,388
52	Total Non-Tariff Sales Fuel Recovery, Energy and Demand	$ 26,705,282	$ 23,367,330	$ 50,072,612	$ (2,215,834)	$ 47,856,778
53	Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)	$ 41,276,627	$ (7,716,227)	$ 33,560,400	$ 2,215,834	$ 35,776,234

54 References:
55 Column [A]: Cooperative Application Schedule H-2A
56 Column [B]: Testimony Crystal Brown
57 Column [C]: Column [A] + Column [B]
57 Column [D] - Rebuttal Testimony Gary Pierson
57 Column [E]: Column [C] + Column [D]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY REBUTTAL AS ADJUSTED	[B] LESS: ALL-REQ. COST ADJUSTMENTS	[C] BASE REQ. ADJUSTOR BASE CALCULATION	[D] PLUS: ALL-REQ..COST ADJUSTMENTS	[E] POWER COST ADJUSTOR BASE CALCULATION
1	Partial Requirements Customers:					
2	Test Year Sales (in kWhs)					716,978,668
3	Base Cost of Power - $/kWh					$ 0.01694
4	Base Cost of Power					$ 12,148,074
	All Requirements Customers:					
5	Test Year Sales (in kWhs)	2,046,390,460	-	2,046,390,460		1,329,411,792
6	Base Cost of Power - $/kWh	$ 0.01748	$ (0.00054)	$ 0.01694	$ 0.00083	$ 0.01777
7	*Base Cost of Power*	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 23,628,160
8	Total Base Cost of Power	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 35,776,234
9	Base Cost of Power Expense					
10	Coal Fired Steam Plant Costs:					
11	Fuel, Coal	$ 42,532,932	$ -	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-	-	-
14	Less: Fixed Fuel Costs	(295,865)	-	(295,865)	-	(295,865)
15	Subtotal	$ 44,546,421	$ -	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:					
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809	-	9,809
19	Less: Fixed Fuel Costs	-	-	-	-	-
20	Subtotal	$ 15,464,540	$ -	$ 15,464,540	$ -	$ 15,464,540
21	Total Fuel Costs	$ 60,010,961	$ -	$ 60,010,961	$ -	$ 60,010,961
22	Purchased Power Energy Costs					
23	Firm Purchases					
24	CRSP	$ 309,547	$ -	$ 309,547	$ -	$ 309,547
25	PacifiCorp	-	-	-	-	-
26	Parker Davis	217,629.00	-	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061.00	-	1,963,061	-	1,963,061
28	Panda Gila River	1,134,573.00	-	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-	-	-
30	*Subtotal Firm Purchases*	$ 3,624,810	$ -	$ 3,624,810	$ -	$ 3,624,810
31	Firm Purchases, Demand	5,519,587	(1,000,872)	$ 4,518,715	1,000,872	$ 5,519,587
32	Nonfirm Purchases, Demand and Energy	6,460,728.0	-	6,460,728	-	6,460,728
33	Total Purchased Power Costs	$ 15,605,125	$ (1,000,872)	$ 14,604,253	$ 1,000,872	$ 15,605,125
34	Firm Wheeling Expenses	$ 7,939,635	(102,500)	$ 7,837,135	102,500	$ 7,939,635
35	Non-firm Wheeling Expenses	77,291	-	77,291	-	77,291
36	Total Firm and Non-Firm Wheeling Expenses	$ 8,016,926	$ (102,500)	$ 7,914,426	$ 102,500	$ 8,016,926
37	TOTAL FUEL COSTS & PURCHASED ENERGY	$ 83,633,012	$ (1,103,372)	$ 82,529,640	$ 1,103,372	$ 83,633,012
38	Less:					
39	Non-tariff Sales Fuel Recovery					
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-	-	-
42	City of Mesa (PSA)	2,566,472	-	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,356,004	-	1,356,004	-	1,356,004
44	SRP	12,778,277	-	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895	-	232,895
46	*Mohave Schedule B Sales*	142,921	-	142,921	-	142,921
47	Subtotal	$ 17,939,124	$ -	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:					
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,333,390	$ -	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ 21,523,388	$ -	$ 21,523,388	$ -	$ 21,523,388
52	Total Non-Tariff Sales Fuel Recovery, Energy and Demand	$ 47,856,778	$ -	$ 47,856,778	$ -	$ 47,856,778
53	Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 35,776,234

54 References:
55 Column [A]: Exhibit GEP-9, Page 1, Column [E]
56 Column [B]: Rebuttal Testimony Gary Pierson
57 Column [C]: Column [A] + Column [B]
58 Column [D]: Rebuttal Testimony Gary Pierson

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

The following resolution was adopted at a **regular meeting** of the Board of Directors of Arizona Electric Power Cooperative, Inc. (AEPCO), held in Benson, Arizona on July 14, 2004.

.RESOLUTION

***WHEREAS**, the Management of Arizona Electric Power Cooperative, Inc., (AEPCO) has presented additional information to the Directors which supports and recommends the need to modify the rates and tariffs for generation service in such a manner that will result in an overall increase in AEPCO's annual operating revenue; and*

***WHEREAS**, the increase in AEPCO's annual operating revenue is necessary to ensure that AEPCO satisfies its mortgage requirements with the Rural Utilities Service (RUS), maintains a satisfactory level of financial integrity, while simultaneously building cooperative equity; and*

***WHEREAS**, Management has prepared and reviewed with the Directors certain financial results culminating in the proposed rates and tariffs which are based on achieving an annual Debt Service Coverage Ratio (DSCR) of 1.05 for the 2003 test year;*

***NOW, THEREFORE BE IT RESOLVED**, that the Board of Directors of Arizona Electric Power Cooperative Inc., hereby authorizes Management to file the required schedules, testimony, applications and other items as may be necessary including a request to implement a fuel and purchased energy adjustor with the appropriate regulatory body, including the Arizona Corporation Commission and the Rural Utilities Service, which will effectuate such rates and tariffs resulting in an increase in annual revenues designed to achieve a 2003 test year financial result equal to a DSCR of 1.05; and*

***BE IT FURTHER RESOLVED**, that the Board of Directors hereby authorizes the Executive Vice President and Chief Executive Officer, or his designee, to sign or otherwise take any and all necessary actions which may be required to cause the new rates and tariffs to become implemented which are designed to achieve the objective of an annual DSCR of 1.05.*

I, Lyn R. Opalka, do hereby certify that I am Secretary of AEPCO, and that the foregoing is a true and correct copy of the Resolution adopted by the Board of Directors at a **regular meeting** held on July 14, 2004.

(seal)

Secretary

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-04100A-04-0527

REBUTTAL TESTIMONY OF

DIRK MINSON

ON BEHALF OF

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

MARCH 16, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Dirk Minson. I am the Chief Financial Officer of the Southwest Transmission Cooperative, Inc. ("SWTC") and my business address is 1000 South Highway 80, Benson, Arizona 85602. I previously filed direct testimony in this matter.

Q. What is the purpose of this testimony?

A. I will summarize AEPCO's rebuttal position as well as respond to a few issues covered in the Staff's testimony. I'll also recommend a different procedure than the one discussed in my direct testimony for dealing with the large loss of revenues resulting from MW&E's cancellation of its 60 MW Firm Service Agreement as of December 31, 2005.

SUMMARY REBUTTAL POSITION

Q. Please summarize AEPCO's reaction to the Staff's testimony.

A. While we don't necessarily agree with all of the Staff's adjustments, its basic recommendation that the Commission authorize an increase in operating revenues of approximately $3.67 million is sufficient. As Mr. Pierson explains in his testimony, that level of revenues produces a TIER of 1.17 and a DSCR of 1.02 after taking into account his reclassification of expenses adjustment associated with the Regulatory Asset Charge ("RAC") revenues adjustment recommended by Ms. Brown. Therefore, to reduce disputed issues and hopefully expedite the issuance of a final rate order, we are accepting all of Ms. Brown's rate base adjustments and, on operating income issues, are suggesting only the one companion expense change to her reclassification adjustment on the RAC as discussed in Mr. Pierson's testimony.

Q. Can you estimate the impact of this rate increase on the average residential customer of the Class A member distribution cooperatives?

A. As I explained in my direct testimony, that is somewhat difficult to do because each distribution cooperative has different rates and varying rate structures. However, we estimate that a residential consumer of SWTC's Class A members using 750 kWh per month would see about a $1.45 increase in the monthly bill as a result of this transmission rate adjustment.

COMMENTS ON SPECIFIC STAFF TESTIMONY

Ms. Brown's Testimony

Q. At pages 19-20 of her testimony, Ms. Brown discusses a small disallowance of expenses relating to Board of Directors minutes and attorney invoice redactions and at pages 21-22 she discusses an adjustment for food and similar expenses. Please respond.

A. Again, in an effort to narrow issues in dispute, we are not contesting the adjustments. However, at pages 5-7 of my AEPCO rebuttal testimony I discuss and provide further context for those adjustments which were also proposed in that case. To avoid repetition, I'll simply incorporate that discussion by reference here.

Q. Please comment on Ms. Brown's recommendation at pages 23-24 of her testimony that SWTC be required to separate the revenues and expenses for Anza in future rate filings.

A. We do not support the recommendation. As I mention in my AEPCO rebuttal testimony, the Commission has never required such a separate cost of service study for Anza before and its transmission service requirements are small. We don't believe the expense of an Anza cost of service study is justified, nor the Staff and Commission effort required to evaluate it.

Mr. Ramirez' Testimony

Q. Please comment on Mr. Ramirez' expressed concerns at pages 7-8 of his testimony that the rates requested in this proceeding will "barely allow the Applicant to cover its debt service."

A. I think that our revised rebuttal case as discussed in Mr. Pierson's testimony and exhibits should address these concerns. Our rebuttal position produces a TIER of 1.17, which is .12 above the RUS mortgage minimum. Again, we are trying to walk what is sometimes a fine line between controlling rates and assuring financial stability for the cooperative. We think our recommendations here accomplish that.

Q. As was the case with AEPCO, Mr. Ramirez also recommends that SWTC improve its equity position to 30% of its capital structure in a reasonable time frame. Please respond.

A. Again, I want to stress that we do not disagree with Mr. Ramirez about the importance of building equity. In the short time that SWTC has been in existence, we've demonstrated that commitment with, among other things, timely rate requests to maintain financial integrity. The rates which we propose here would generate about $890,000 in net margins on an annual basis. Absent other changes, this level of margins would build SWTC's equity ratio to 15% in about ten years. However, for the reasons I stated at pages 8-9 of my AEPCO rebuttal testimony, I would encourage the Commission <u>not</u> to adopt a fixed equity target of 30% over a particular time frame and also feel that the equity goal of 30% for a transmission cooperative like SWTC is unnecessarily high.

Q. Finally, please comment on Mr. Ramirez' suggestion that the Commission restrict future patronage distributions until it has achieved a 30% capital structure.

A. SWTC has no plans in the foreseeable future to make any patronage distributions. We don't see a need for Commission restrictions because we are already subject to RUS and CFC mortgage controls on that subject. If, however, the Commission wants to impose a restriction, we would suggest that it simply order SWTC to comply with its mortgage restrictions.

MW&E 60 MW FIRM REVENUE LOSS

Q. Mr. Minson, at pages 6-10 of your direct testimony, you described the fact that the loss of both firm and non-firm transmission revenues, as a result of the Morenci Water & Electric Company ("MW&E") bypass of SWTC's transmission system, was a major reason for this rate increase request. Please update the Commission on what has happened on that subject since you filed your testimony last July.

A. Effective November 1, 2004, MW&E stopped taking any non-firm transmission service from SWTC following completion of its direct intertie to the Tucson Electric Power transmission system. We had anticipated that would happen and made an adjustment to test year revenues for the approximately $2.8 million dollars in lost non-firm revenues. So, that non-firm revenue loss is adequately covered by Staff and our recommendations here. However, the second large loss of approximately $2.37 million in firm revenues will occur on December 31 of this year when MW&E's cancellation of its firm Transmission Service Agreement takes effect. The financial impact on SWTC of this revenue loss only a few months after the rate order is entered cannot be overstated. It is more than double SWTC's requested, test year adjusted net margin. In order to address this loss, without the necessity of another full rate case, I have an alternate procedure to suggest than the one outlined in my direct testimony.

Q. Please describe it.

A. As explained in Mr. Pierson's testimony, we ask that the Commission authorize rates for the balance of this year which are set forth in column C of his Exhibit GEP-11. We also request that the Commission authorize in this decision new rates, set forth in column D of Exhibit GEP-11, to take effect on January 1, 2006—the day after the MW&E cancellation of its 60 MW firm agreement takes effect. These revised rates have been designed based upon the adjusted 2003 test year and take into account only the loss of the revenues from MW&E's 60 MW firm agreement. They are designed simply to return SWTC to the TIER, DSCR and rate of return levels we request be authorized in this decision. On December 1 of this year, we propose to file with the Commission a statement verifying that MW&E's cancellation of the Firm Service Agreement remains in effect and no new MW&E Service Agreement has been entered into together with revised tariff pages reflecting the rates set forth in column D of Exhibit GEP-11. Unless the Commission takes action to suspend the filing, the revised rates would then take effect on January 1, 2006. This procedure provides assurances that the new rates are just and reasonable based upon the test year data and also provides a timely, cost effective solution to a large rate and revenue issue for SWTC.

CONCLUSION

Q. Please summarize SWTC's requests.

A. We request that the Commission authorize (1) the rates set forth in column C of Exhibit GEP-11 through December 31, 2005 and (2) the rates set forth in column D of Exhibit GEP-11 on the procedures I have described effective January 1, 2006. We also ask that a rate order be issued as promptly as possible.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

15169-6/1257396

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-04100A-04-0527

REBUTTAL TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

MARCH 16, 2005

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INTRODUCTION

Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored direct testimony for Southwest Transmission Cooperative, Inc. ("SWTC") in this matter?

A. Yes, I am.

Q. Have you reviewed the direct testimony of Staff witnesses Crystal Brown, Alejandro Ramirez, Erin Casper and Jerry Smith filed February 23, 2005 in this matter?

A. Yes, I have. As Mr. Minson discusses in his testimony, in order to narrow disputed issues and reduce complexity, for rebuttal purposes SWTC accepts all six of the Rate Base Adjustments proposed by Ms. Brown at pages 7-15 of her testimony. Further, SWTC accepts four of the five Operating Income Adjustments proposed by Ms. Brown at pages 18-22 of her testimony as follows:

Adjustment No 2 – Legal Expense	Schedule CSB-12
Adjustment No 3 – Employee Vacancy Level Normalization	Schedule CSB-14
Adjustment No 4 – Food & Other Expenses	Schedule CSB-15
Adjustment No 5 – Interest on Long Term Debt	Schedule CSB-16

Therefore, my rebuttal testimony will focus only on Ms. Brown's Regulatory Asset Charge ("RAC") adjustment discussed at pages 17-18 of her testimony.

In addition, I am sponsoring Exhibits GEP-2 through GEP-11 in support of SWTC's rebuttal position on the development of revenue requirements and rates in this matter as well as additional rates we recommend be authorized in this order to take effect on January 1, 2006.

RATE BASE – SWTC REBUTTAL POSITION

Q. Have you reviewed the Staff's testimony on original cost rate base and the determination of fair value for this proceeding?

A. Yes, I have. As I indicated, SWTC accepts the Staff's proposed rate base of $76,345,655 as set forth in Ms. Brown's Schedule CSB-2 as the fair value rate base.

OPERATING INCOME – SWTC REBUTTAL POSITION

Q. What is the rebuttal position of SWTC regarding operating income?

A. As shown on Exhibit GEP-4 and Exhibit GEP-5, SWTC proposes test year revenues of $25,148,196, expenses of $22,668,132, operating margins before interest on long-term debt of $2,480,064 and a net margin loss of $2,773,182. The test year revenues are the same as Staff's position, the expenses are $2,707,122 less and margins before interest on long-term debt are greater by the same amount. Further, RAC non-operating margins are $2,559,926 less and the net margins loss amount is $147,196 less than Staff's position as a result of SWTC's reclassification of expenses associated with the RAC.

Rebuttal Adjustment No. 1 – Regulatory Asset Charge

Q. Have you reviewed Ms. Brown's proposed adjustment on the RAC?

A. Yes, I have. Staff proposes to reclassify the revenues that SWTC collects under the RAC provisions of its tariff as non-operating revenue. Furthermore, Staff proposes to adjust the RAC revenue based upon a three-year average of the rates per kWh that are effective in 2004, 2005 and 2006. The effect of the adjustment reduces operating revenues by $2,707,122, increases non-operating revenues by $2,559,926 and decreases net margins by $147,196.

Q. Please describe the Company's position on Ms. Brown's adjustment.

A. Although this treatment of the RAC as non-operating income is different than the one followed in SWTC's financial statements, we don't object either to it or the three-year averaging of the RAC. However, for consistency, the adjustment should also reclassify the associated amortization of the regulatory assets that is recorded as an operating expense. During the test year, SWTC billed $2,707,122 in RAC revenues and, correspondingly, recorded $2,707,122 in amortization expense. If the revenues from the RAC charges are reclassified as non-operating revenue as Ms. Brown suggests, then the associated expense relating to those regulatory assets should also be recorded as a non-operating expense.

Q. Have you prepared an adjustment describing this position?

A. Yes. Exhibit GEP-6 contains the rebuttal adjustment that we propose. This adjustment completes Ms. Brown's reclassification adjustment by reducing depreciation and amortization expense by $2,707,122 and increasing non-operating expense by $2,559,926, which increases net margins by $147,196.

SUMMARY REBUTTAL POSITION

Q. Have you prepared exhibits which summarize SWTC's current positions and requests?

A. Yes, I have. Exhibits GEP-2, GEP-3, GEP-4 and GEP-5 summarize revenue requirement, rate base and operating income data. With reference to Exhibit GEP-2, we request that the Commission authorize an increase in operating revenues of $3,666,668 (column C, l. 6)—which is the same amount recommended by Staff. This would result in an 8.05% rate of return on the rate base of $76,345,655, a TIER of 1.17 and a DSCR of 1.02.

Q. What are the recommended rates?

A. Exhibit GEP-11, column C sets forth the rates we would ask that the Commission approve to be effective through December 31, 2005.

MW&E 60 MW FIRM POINT-TO-POINT CONTRACT CANCELLATION

Q. Mr. Pierson, have you also prepared exhibits reflecting revised rates SWTC requests the Commission approve effective January 1, 2006 to compensate for the loss of the MW&E 60 MW firm revenues?

A. Yes. As background, during the course of this proceeding, SWTC has discussed with Staff ways to address the termination of the 60 MW Firm Point-to-Point Service Agreement between SWTC and Morenci Water & Electric Company ("MW&E"). MW&E has cancelled the Agreement effective December 31, 2005 and is now acquiring transmission service from Tucson Electric Power after construction of an intertie with their system.

Q. Mr. Minson discusses how SWTC recommends this revenue loss be handled. Have you prepared exhibits supporting the revised rates proposed to be effective on January 1, 2006?

A. Yes, I have. Exhibit GEP-7 shows the reduction in MW&E test year point-to-point and load dispatch and system control revenues of $1,990,800 and $303,840, respectively. Exhibits GEP-8 and GEP-9 then summarize the test year Operating Income effects of removing the $2,294,640 in lost MW&E revenues. Exhibit GEP-10 then summarizes the effects of this adjustment on the test year results for the MW&E contract termination. Referring to Exhibit GEP-10, column D, l. 6, the required increase in revenues of $2,294,640 to compensate for the MW&E firm revenue loss will produce exactly the same TIER, DSCR and rate of return percentages (shown on lines 16, 18 and 21) that the rates effective through December 31, 2005 will produce.

Q. Have you prepared an exhibit showing the rates SWTC requests the Commission authorize to be effective on January 1, 2006 following the loss of the MW&E firm revenues?

A. Yes. Exhibit GEP-11, column D sets forth the rates we ask the Commission approve to be effective on January 1, 2006.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

15169-6/1257415

Southwest Transmission Cooperative, Inc. Exhibit GEP-2
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL FILED With RAC	[B] STAFF DIRECT POSITION With RAC	[C] COMPANY REBUTTAL POSITION With RAC
1	Adjusted Operating Income (Loss)	$ 2,224,809	$ (227,058)	$ 2,480,064
2	Depreciation and Amortization	$ 6,852,107	$ 6,852,107	$ 4,144,985
3	Income Tax Expense	-	-	-
4	Interest Expense on Long-term Debt	$ 5,168,413	$ 5,302,088	$ 5,302,088
5	Principal Repayment	$ 6,349,686	$ 7,358,610	$ 7,358,610
6	Recommended Increase in Operating Revenue	$ 3,666,668	$ 3,666,668	$ 3,666,668
7	Percent Increase (Line 6 / Line 10)	13.16%	14.58%	14.58%
8	Network Service and Other Revenue	$ 25,148,196	$ 25,148,196	$ 25,148,196
9	Regulatory Asset Charge ("RAC")[1]	$ 2,707,122	$ -	$ -
10	Adjusted Test Year Operating Revenue	$ 27,855,318	$ 25,148,196	$ 25,148,196
11	Total Annual Operating Revenue	$ 31,521,986	$ 28,814,864	$ 28,814,864
12	Margins Before Interest on Long Term Debt	$ 5,891,477	$ 3,439,610	$ 6,146,732
13	Net Margin	$ 771,906	$ 746,290	$ 893,486
14a	Regulatory Asset Charges:			
14b	*Normalized RAC Revenue, Non-operating*	-	$ 2,559,926	$ 2,559,926
14c	Normalized RAC Revenue, Non-operating	-	$ -	$ 2,559,926
14d	Net RAC Non-operating Margin	N/A	$ 2,559,926	$ -
15	Total Operating Revenue and RAC Revenue		$ 5,999,536	$ 6,146,732
16	Cooperative Net TIER (L4+L13) / L4	1.15	N/A	1.17
17	Staff Operating TIER (L3+L12+L14b) / L4	N/A	1.13	1.16
18	Cooperative DSC (L2+L4+L13+L14c)/(L4+L5)	1.11	N/A	1.02
19	Staff DSC (L2+L3+L12+14b)/(L4+L5)	N/A	1.02	1.02
20	Adjusted Rate Base	$ 79,392,885	$ 76,345,655	$ 76,345,655
21	Rate of Return (L12 / L20)	7.42%	4.51%	8.05%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Schedules CSB-1, Column [C]
Column [C] Exhibits GEP-3 & GEP-4, Rebuttal Testimony Gary Pierson

Southwest Transmission Cooperative, Inc.
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Exhibit GEP-3

RATE BASE - ORIGINAL COST

LINE NO.		(A) COMPANY AS FILED	(B) STAFF DIRECT POSITION	(C) COMPANY REBUTTAL POSITION
1	Plant in Service	$ 131,520,683	$ 131,516,270	$ 131,516,270
2	Less: Accumulated Depreciation	(55,772,833)	(55,798,589)	(55,798,589)
3	Net Plant in Service	75,747,850	75,717,681	75,717,681
	LESS:			
4	Advances in Aid of Construction (AIAC)	0	0	0
5	Contributions in Aid of Construction (CIAC)	0	0	0
6	Less: Accumulated Amortization	0	0	0
7	Net CIAC	0	0	0
8	Total Advances and Contributions	0	0	0
9	Member Advances	0	(228,188)	(228,188)
	ADD:			
10	Working Capital	3,122,116	856,162	856,162
11	Plant Held for Future Use	377,214	0	0
12	Deferred Debits	145,705	0	0
13	Total Rate Base	$ 79,392,885	$ 76,345,655	$ 76,345,655

References:
Column [A], Company Schedule B-1, Page 1;
Column [B]: Schedule CSB-2
Column [C]: Pierson Rebuttal Testimony

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Exhibit GEP-4

OPERATING INCOME - TEST YEAR, STAFF ADJUSTED AND COMPANY PROPOSED

LINE NO.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR AS ADJUSTED	[C] COMPANY REBUTTAL TEST YEAR ADJUSTMENTS	[D] COMPANY REBUTTAL TEST YEAR AS ADJUSTED	[E] COMPANY REBUTTAL PROPOSED CHANGES	[F] COMPANY REBUTTAL RECOMMENDED
1	*REVENUES:*						
2	Network Transmission Serv & Other Revenue	$ 25,148,196	$ 25,148,196	$ -	$ 25,148,196	$ 3,666,668	$ 28,814,864
3	Regulatory Asset Charge	2,707,122	-	-	-	-	-
4	Total Electric Transmission Revenue	27,855,318	25,148,196	-	25,148,196	3,666,668	28,814,864
5	*EXPENSES:*						
6	Energy	2,541,334	2,541,334	-	2,541,334	-	2,541,334
7	Transmission	7,649,597	7,535,913	-	7,535,913	-	7,535,913
8	Administrative and General	3,872,157	3,730,586	-	3,730,586	-	3,730,586
9	Maintenance	2,429,390	2,429,390	-	2,429,390	-	2,429,390
10	Maintenance - General Plant	79	79	-	79	-	79
11	Depreciation and Amortization	6,852,107	6,852,107	(2,707,122)	4,144,985	-	4,144,985
12	ACC Gross Revenue Taxes	-	-	-	-	-	-
13	Property Taxes	2,285,845	2,285,845	-	2,285,845	-	2,285,845
14	Income Taxes	-	-	-	-	-	-
15	Total Operating Expenses	25,630,509	25,375,254	(2,707,122)	22,668,132	-	22,668,132
16	Operating Margin Before Interest on L.T.- Debt	2,224,809	(227,058)	2,707,122	2,480,064	3,666,668	6,146,732
17	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*						
18	Interest on Long-term Debt	5,168,413	5,302,088	-	5,302,088	-	5,302,088
19	Other Interest & Other Deductions	232,030	232,030	-	232,030	-	232,030
20	Total Interest & Other Deductions	5,400,443	5,534,118	-	5,534,118	-	5,534,118
21	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(3,175,634)	(5,761,176)	2,707,122	(3,054,054)	3,666,668	612,614
22	*NON-OPERATING MARGINS*						
23	Interest Income	172,901	172,901	-	172,901	-	172,901
24	Other Non-operating Income	107,971	107,971	-	107,971	-	107,971
25	Total Non-Operating Margins	280,872	280,872	-	280,872	-	280,872
26	*REGULATORY ASSET CHARGE*						
	Regulatory Asset Charge Revenues	-	2,559,926	-	2,559,926	-	2,559,926
	Regulatory Asset Amortization Expense	-	-	2,559,926	2,559,926	-	2,559,926
	Net Regulatory Asset Charge	-	2,559,926	(2,559,926)	-	-	-
27	*NET MARGINS (LOSS)*	$ (2,894,762)	$ (2,920,378)	$ 147,196	$ (2,773,182)	$ 3,666,668	$ 893,486

25 References:
26 Column [A]: Company Schedule C-1, Page 2
27 Column [B]: Schedule CSB-11
28 Column [C]: Exhibit GEP-5
29 Column (D): Column (B) + Column (C)
30 Column (E): Exhibit GEP-2
31 Column (F): Column (C) + Column (D)

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Exhibit GEP-5

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] ADJ #1 Regulatory Asset Amortization Adjustment	[C] COMPANY REBUTTAL ADJUSTED
	REVENUES:		Ref: Sch GEP-6	
1	Network Transmission Service	$ 13,104,192	$ -	$ 13,104,192
2	Point to Point	7,617,540	-	7,617,540
3	Total Electric Revenue	20,721,732	-	20,721,732
4	Load Dispatch and System Control	2,824,224	-	2,824,224
5	Direct Access Facilities	515,580	-	515,580
6	Regulatory Asset Charge	-	-	-
7	Other Operating Revenue	413,318	-	413,318
8	Ancilliary Services From AEPCO	-	-	-
9	Special Contracts	673,342	-	673,342
10	Total Revenues	25,148,196	-	25,148,196
	OPERATING EXPENSES:			
11	Energy	2,541,334	-	2,541,334
12	Transmission	7,535,913	-	7,535,913
13	Administrative and General	3,730,586	-	3,730,586
14	Maintenance	2,429,390	-	2,429,390
15	Maintenance - General Plant	79	-	79
16	Depreciation and Amortization	6,852,107	(2,707,122)	4,144,985
17	ACC Gross Revenue Taxes	-	-	-
18	Other Taxes	2,285,845	-	2,285,845
19	Income Taxes	-	-	-
20	Total Operating Expenses	25,375,254	(2,707,122)	22,668,132
21	Operating Margin Before Interest on L.T.- Debt	(227,058)	2,707,122	2,480,064
23	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*			
24	Interest on Long-term Debt	5,302,088	-	5,302,088
25	Other Interest & Other Dedcutions	232,030	-	232,030
26	Total Interest & Other Deductions	5,534,118	-	5,534,118
27	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(5,761,176)	2,707,122	(3,054,054)
28	*NON-OPERATING MARGINS*			
29	Interest Income	172,901	-	172,901
30	Other Non-operating Income	107,971	-	107,971
31	Total Non-Operating Margins	280,872	-	280,872
32	*REGULATORY ASSET CHARGE*			
33	Regulatory Asset Charge Revenues	2,559,926	-	2,559,926
33	Regulatory Asset Amortization Expense	-	2,559,926	2,559,926
34	Net Regulatory Asset Charge	2,559,926	(2,559,926)	-
33	*NET MARGINS (LOSS)*	$ (2,920,378)	$ 147,196	$ (2,773,182)

Southwest Transmission Cooperative, Inc. Exhibit GEP-6
Docket No. E-04100A-04-0527
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REBUTTAL ADJUSTMENT NO. 1 - REGULATORY ASSET CHARGE

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	STAFF AS ADJUSTED	COMPANY REBUTTAL ADJUSTMENTS	COMPANY REBUTTAL AS ADJUSTED
1	Revenue	$ 25,148,196	$ -	$ 25,148,196
2	Regulatory Asset Charge	-	-	-
3	Total Revenue	25,148,196	-	25,148,196
4	Expense	25,630,509	(2,707,122)	22,923,387
5	Operating Margin Before Interest	(482,313)	2,707,122	2,224,809
6	Total Interest	5,400,423	-	5,400,423
7	Margins After Interest Expense	(5,882,736)	2,707,122	(3,175,614)
8	Non-Operating Margins	280,872	-	280,872
9	Regulatory Asset Charge:			
9a	Revenue	2,559,926	-	2,559,926
9b	Expense	-	2,559,926	2,559,926
9c	Margin	2,559,926	(2,559,926)	-
10	Net Margin	$ (3,041,938)	$ 147,196	$ (2,894,742)

CALCULATION OF NORMALIZED REGULATORY ASSET CHARGE

		[A]	[B]	[C]
	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
11		Total kWhs		Total kWhs
12	Anza	44,660,813	-	44,660,813
13	Duncan	26,782,590	-	26,782,590
14	Graham	136,552,300	-	136,552,300
15	Mohave 1	611,433,890	-	611,433,890
16	Sulphur	662,992,990	-	662,992,990
17	TRICO (See Note Below)	437,521,797	-	437,521,797
18		1,919,944,380		1,919,944,380
19	*Regulatory Asset Charge*	$ *0.00141*	$ (0.00008)	$ 0.00133
20	Regulatory Asset Charge (L8 x L9)	$ 2,707,122	(147,196)	$ 2,559,926
21	Regulatory Asset Amortization	$ 2,707,122	(147,196)	2,559,926
22	Net Adjustment	$ -	$ -	$ -

23			RAC
24			Decision No.62758
25		2004 RAC	$ 0.00137
26		2005 RAC	$ 0.00133
27	Note:	2006 RAC	$ 0.00130
28	The Cooperative filed 437,520,942 kWhs.		$ 0.00400
29	Staff used the Cooperative's actual kWhs	Divided by	3
30	of 437,521,797 to reconcile to the $2,707,122		$ 0.00133
31	in RAC revenue shown on Schedule C1, Page 3, Line 6		

32 References:
33 Column [A]: Schedule CSB-12, Column [C]
34 Column [B]: Rebuttal Testimony Gary Pierson
35 Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
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Exhibit GEP-7

MWE CONTRACT CANCELLATION

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY ADJUSTMENTS	[C] COMPANY AS ADJUSTED
1	MWE 60 MW Contract Revenues:			
2	Point-to-Point Revenue	$ 1,990,800	$ (1,990,800)	$ -
3	Load Dispatch and System Control	303,840	(303,840)	-
4	Total	$ 2,294,640	$ (2,294,640)	$ -

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Exhibit GEP-8

OPERATING INCOME - TEST YEAR, STAFF ADJUSTED AND COMPANY PROPOSED - WITH MWE 60 MW PtP CONTRACT ADJUSTMENT

LINE NO.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR AS ADJUSTED	[C] COMPANY MWE TEST YEAR ADJUSTMENTS	[D] COMPANY MWE TEST YEAR AS ADJUSTED	[E] COMPANY MWE PROPOSED CHANGES	[F] COMPANY RECOMMENDED With MWE ADJ
1	*REVENUES:*						
2	Network Transmission Serv & Other Revenue	$ 25,148,196	$ 25,148,196	$ (2,294,640)	$ 22,853,556	$ 5,961,308	$ 28,814,864
3	Regulatory Asset Charge	2,707,122	-	-	-	-	-
4	Total Electric Transmission Revenue	27,855,318	25,148,196	(2,294,640)	22,853,556	5,961,308	28,814,864
5	*EXPENSES:*						
6	Energy	2,541,334	2,541,334	-	2,541,334	-	2,541,334
7	Transmission	7,649,597	7,535,913	-	7,535,913	-	7,535,913
8	Administrative and General	3,872,157	3,730,586	-	3,730,586	-	3,730,586
9	Maintenance	2,429,390	2,429,390	-	2,429,390	-	2,429,390
10	Maintenance - General Plant	79	79	-	79	-	79
11	Depreciation and Amortization	6,852,107	6,852,107	(2,707,122)	4,144,985	-	4,144,985
12	ACC Gross Revenue Taxes	-	-	-	-	-	-
13	Property Taxes	2,285,845	2,285,845	-	2,285,845	-	2,285,845
14	Income Taxes	-	-	-	-	-	-
15	Total Operating Expenses	25,630,509	25,375,254	(2,707,122)	22,668,132	-	22,668,132
16	Operating Margin Before Interest on L.T.- Debt	2,224,809	(227,058)	412,482	185,424	5,961,308	6,146,732
17	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*						
18	Interest on Long-term Debt	5,168,413	5,302,088	-	5,302,088	-	5,302,088
19	Other Interest & Other Dedcutions	232,030	232,030	-	232,030	-	232,030
20	Total Interest & Other Deductions	5,400,443	5,534,118	-	5,534,118	-	5,534,118
21	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(3,175,634)	(5,761,176)	412,482	(5,348,694)	5,961,308	612,614
22	*NON-OPERATING MARGINS*						
23	Interest Income	172,901	172,901	-	172,901	-	172,901
24	Other Non-operating Income	107,971	107,971	-	107,971	-	107,971
25	Total Non-Operating Margins	280,872	280,872	-	280,872	-	280,872
26	*REGULATORY ASSET CHARGE*						
	Regulatory Asset Charge Revenues	-	2,559,926	-	2,559,926	-	2,559,926
	Regulatory Asset Amortization Expense	-	-	2,559,926	2,559,926	-	2,559,926
	Net Regulatory Asset Charge	-	2,559,926	(2,559,926)	-	-	-
27	*NET MARGINS (LOSS)*	$ (2,894,762)	$ (2,920,378)	$ (2,147,444)	$ (5,067,822)	$ 5,961,308	$ 893,486

25 References:
26 Column [A]: Company Schedule C-1, Page 2
27 Column [B]: Schedule CSB-11
28 Column [C]: Exhibit GEP-5
29 Column (D): Column (B) + Column (C)
30 Column (E):Exhibit GEP-10
31 Column (E): Column (C) + Column (D)

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Exhibit GEP-9

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR - WITH MWE 60 MW PtP CONTRACT ADJUSTMEN

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] ADJ #1 Regulatory Asset Amortization Adjustment	[C] ADJ #2 MW&E Firm P-t-P Revenue	[D] COMPANY MWE ADJUSTED
	REVENUES:		Ref: Sch GEP-6	Ref: Sch GEP-7	
1	Network Transmission Service	$ 13,104,192	$ -	$ -	$ 13,104,192
2	Point to Point	7,617,540	-	(1,990,800)	5,626,740
3	Total Electric Revenue	20,721,732	-	(1,990,800)	18,730,932
4	Load Dispatch and System Control	2,824,224	-	(303,840)	2,520,384
5	Direct Access Facilities	515,580	-	-	515,580
6	Regulatory Asset Charge	-	-	-	-
7	Other Operating Revenue	413,318	-	-	413,318
8	Ancilliary Services From AEPCO	-	-	-	-
9	Special Contracts	673,342	-	-	673,342
10	Total Revenues	25,148,196	-	(2,294,640)	22,853,556
	OPERATING EXPENSES:				
11	Energy	2,541,334	-	-	2,541,334
12	Transmission	7,535,913	-	-	7,535,913
13	Administrative and General	3,730,586	-	-	3,730,586
14	Maintenance	2,429,390	-	-	2,429,390
15	Maintenance - General Plant	79	-	-	79
16	Depreciation and Amortization	6,852,107	(2,707,122)	-	4,144,985
17	ACC Gross Revenue Taxes	-	-	-	-
18	Other Taxes	2,285,845	-	-	2,285,845
19	Income Taxes	-	-	-	-
20	Total Operating Expenses	25,375,254	(2,707,122)	-	22,668,132
21	Operating Margin Before Interest on L.T.- Debt	(227,058)	2,707,122	(2,294,640)	185,424
23	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*				
24	Interest on Long-term Debt	5,302,088	-	-	5,302,088
25	Other Interest & Other Dedcutions	232,030	-	-	232,030
26	Total Interest & Other Deductions	5,534,118	-	-	5,534,118
27	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(5,761,176)	2,707,122	(2,294,640)	(5,348,694)
28	*NON-OPERATING MARGINS*				
29	Interest Income	172,901	-	-	172,901
30	Other Non-operating Income	107,971	-	-	107,971
31	Total Non-Operating Margins	280,872	-	-	280,872
32	*REGULATORY ASSET CHARGE*				
33	Regulatory Asset Charge Revenues	2,559,926	-	-	2,559,926
33	Regulatory Asset Amortization Expense	-	2,559,926	-	2,559,926
34	Net Regulatory Asset Charge	2,559,926	(2,559,926)	-	-
33	*NET MARGINS (LOSS)*	$ (2,920,378)	$ 147,196	$ (2,294,640)	$ (5,067,822)

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Exhibit GEP-10

REVENUE REQUIREMENT - WITH MWE 60 MW PtP CONTRACT ADJUSTMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL COST With RAC	[B] STAFF ORIGINAL COST With RAC	[C] COMPANY REBUTTAL POSITION With RAC	[D] COMPANY REBUTTAL POSITION With MWE Adj
1	Adjusted Operating Income (Loss)	$ 2,224,809	$ (227,058)	$ 2,480,064	$ 185,424
2	Depreciation and Amortization	$ 6,852,107	$ 6,852,107	$ 4,144,985	$ 4,144,985
3	Income Tax Expense	-	-	-	-
4	Interest Expense on Long-term Debt	$ 5,168,413	$ 5,302,088	$ 5,302,088	$ 5,302,088
5	Principal Repayment	$ 6,349,686	$ 7,358,610	$ 7,358,610	$ 7,358,610
6	Recommended Increase in Operating Revenue	$ 3,666,668	$ 3,666,668	$ 3,666,668	$ 5,961,308
7	Percent Increase (Line 6 / Line 10)	13.16%	14.58%	14.58%	26.08%
8	Network Service and Other Revenue	$ 25,148,196	$ 25,148,196	$ 25,148,196	$ 22,853,556
9	Regulatory Asset Charge ("RAC")[1]	$ 2,707,122	$ -	$ -	$ -
10	Adjusted Test Year Operating Revenue	$ 27,855,318	$ 25,148,196	$ 25,148,196	$ 22,853,556
11	Total Annual Operating Revenue	$ 31,521,986	$ 28,814,864	$ 28,814,864	$ 28,814,864
12	Margins Before Interest on Long Term Debt	$ 5,891,477	$ 3,439,610	$ 6,146,732	$ 6,146,732
13	Net Margin	$ 771,906	$ 746,290	$ 893,486	$ 893,486
14a	Regulaory Asset Charges:				
14b	Normalized RAC Revenue, Non-operating	-	$ 2,559,926	$ 2,559,926	$ 2,559,926
14c	Normalized RAC Amortization, Non-operating	-	$ -	$ 2,559,926	$ 2,559,926
14d	Net RAC Non-operating Margin	N/A	$ 2,559,926	$ -	$ -
15	Total Operating Revenue and RAC Margins	N/A	$ 5,999,536	$ 6,146,732	$ 6,146,732
16	Cooperative Net TIER (L4+L13) / L4	1.15	N/A	1.17	1.17
17	Staff Operating TIER (L3+L12+L14b) / L4	N/A	1.13	1.16	1.16
18	Cooperative DSC (L2+L4+L13+L14c)/(L4+L5)	1.11	N/A	1.02	1.02
19	Staff DSC (L2+L3+L12+14b)/(L4+L5)	N/A	1.02	1.02	1.02
20	Adjusted Rate Base	$ 79,392,885	$ 76,345,655	$ 76,345,655	$ 76,345,655
21	Rate of Return (L12 / L20)	7.42%	4.51%	8.05%	8.05%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Schedules CSB-1
Column [C] Exhibits GEP-3 & GEP-4, Rebuttal Testimony Gary Pierson
Column [D] Exhibits GEP-8 & GEP-9, Rebuttal Testimony Gary Pierson

Southwest Transmission Cooperative, Inc.
Docket No. E-01773A-04-0527
Test Year Ended December 31, 2003

Exhibit GEP-11

SUMMARY OF PROPOSED RATES

Line No.	Description	[A] Company As Filed	[B] Staff Direct Position	[C] Company Rebuttal Position	[D] Company Rebuttal Position With MWE ADJ
1	Network Transmission Service:				
2	Transmission Rate - $/Month	$ 1,418,473	$ 1,420,542	$ 1,420,542	$1,566,081
3	Ancillary Services:				
4	Schedule 1: System Control and Load Dispatch - $/kW Mon.	$ 0.289	$ 0.289	$ 0.289	$ 0.289
5	Schedule 2: Cost of Reactive Power (VAR) Production - $/kW Mon.	$ 0.064	$ 0.080	$ 0.080	$ 0.080
6	Schedule 3: Regulation and Frequency Response - $/kW Mon.	$ 0.4111	$ 0.4280	$ 0.4280	$ 0.4280
7	Schedule 4: Energy Imbalance - $/MWh	$ 20.69	$ 20.32	$ 20.32	$ 20.32
8	Schedule 5: Operating Reserves - Spinning - $/kW Mon.	$ 0.6205	$ 0.6460	$ 0.6460	$ 0.6460
9	Schedule 6: Operating Reserves - Supplemental - $/kW Mon.	$ 0.4114	$ 0.4170	$ 0.4170	$ 0.4170
10					
	Point-to-Point				
11	Point-to-Point Rate - $/ kW Month	$ 3.032	$ 3.022	$ 3.022	$ 3.334
12	Ancillary Services:				
13	Schedule 1: System Control and Load Dispatch - $/kW Mon.	$ 0.289	$ 0.289	$ 0.289	$ 0.289
14	Schedule 2: Cost of Reactive Power (VAR) Production - $/kW Mon.	$ 0.051	$ 0.064	$ 0.064	$ 0.064
15	Schedule 3: Regulation and Frequency Response - $/kW Mon.	$ 0.4111	$ 0.4280	$ 0.4280	$ 0.4280
16	Schedule 4: Energy Imbalance - $/MWh	$ 20.69	$ 20.32	$ 20.32	$ 20.32
17	Schedule 5: Operating Reserves - Spinning - $/kW Mon.	$ 0.6205	$ 0.6460	$ 0.6460	$ 0.6460
18	Schedule 6: Operating Reserves - Supplemental - $/kW Mon.	$ 0.4114	$ 0.4170	$ 0.4170	$ 0.4170

References:

Column [A] - Company Original Filing, Schedules G2A
Column [B] - Schedules EEC-5, EEC-6, EEC-8, EEC-9, EEC-10 and EEC-11
Column [C] - Gary Pierson Rebuttal Testimony and Workpapers
Column [D] - Gary Pierson Rebuttal Testimony and Workpapers